STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **Consumers Energy Company** for the reconciliation of power supply cost recovery costs and revenues for the calendar year 2009.	)))))	Case No. U-15675-R

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on March 30, 2011.

Exceptions, if any, must be filed with the Michigan Public Service Commission, P.O. Box 30221, 6545 Mercantile Way, Lansing, Michigan 48909, and served on all other parties of record on or before April 20, 2011, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before May 4, 2011. **The Commission has selected this case for participation in its Paperless Electronic Filings Program. No paper documents will be required to be filed in this case.**

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

STATE OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Sharon L. Feldman

Digitally signed by Sharon L. Feldman
DN: cn=Sharon L. Feldman, c=US, email=feldmans@michigan.gov
Date: 2011.03.30 11:59:03 -04'00'

Sharon L. Feldman
Administrative Law Judge

March 30, 2011
Lansing, Michigan

S T A T E O F M I C H I G A N

STATE OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
Consumers Energy Company for	)	Case No. U-15675-R
the reconciliation of power supply	)	
cost recovery costs and revenues	)	
for the calendar year 2009.	)	

PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY

This Proposal for Decision (PFD) addresses Consumers Energy Company's March 31, 2010 filing seeking approval of its reconciliation of Power Supply Cost Recovery costs and revenues for calendar year 2009.

As originally filed, the company's reconciliation identified total 2009 PSCR costs of $1.598 billion, and revenues of $1.544 billion, resulting in an underrecovery of $54 million for 2009, and a cumulative underrecovery of $39 million, including interest. The company also sought to recover unrecovered balances for 2004 and 2005, resulting in a total requested underrecovery of $41 million. In revised calculations adopting Staff adjustments, the company now seeks a cumulative underrecovery of $34,378,062, including interest.

At the May 4, 2010 prehearing conference, the company and Staff appeared, and the following additional parties appeared and were granted intervention: the Attorney General; the Michigan Environmental Council (MEC); the Michigan Community Action Agency Association (MCAAA); Hemlock Semiconductor Corporation; Midland Cogeneration Venture Limited Partnership (MCV); and Cadillac Renewable Energy, LLC, Genesee Power Station Limited Partnership, Grayling Generating Station limited Partnership, Hillman Power Company, LLC, TES Filer City Limited Partnership, Viking Energy of Lincoln, and Viking Energy of McBain (collectively referred to as the Biomass Merchant Plants or "BMPs").

Following the schedule established at the prehearing conference, on May 21, 2010, the BMPs filed testimony and exhibits; on November 30, 2010, Staff, MEC, and the Attorney General filed testimony and exhibits; and on December 20, 2010, Consumers Energy and the BMPs filed rebuttal testimony and exhibits. In addition, the Attorney General filed supplemental testimony on December 17, 2010, and Consumers Energy filed supplemental rebuttal and second supplemental rebuttal testimony on January 5 and January 7, 2011.

At hearings on January 11 and 12, 2011, eight witnesses appeared and were cross-examined, while the testimony of ten additional witnesses was bound into the record by agreement of the parties, without the need for the witnesses to appear. A motion to strike a portion of the testimony of the Attorney General's witness, filed by the BMPs, was denied. Also at the hearing, and pursuant to notice, Consumers Energy's motion for a protective order was addressed, and with the consent of all parties present, a protective order was entered that was more limited in scope than the order the utility initially sought.

Following the schedule established on the last day of the hearing, Consumers Energy, the BMPs, MEC and the Attorney General filed briefs on February 11, 2011; Consumers Energy, the BMPs, MEC, the Attorney General and Staff filed reply briefs on February 25, 2011.

The evidentiary record is contained in 683 transcript pages, and 86 exhibits. A brief overview of the record and the parties' positions is presented in section II below.

II.

OVERVIEW OF THE RECORD AND DISPUTED ISSUES

The company's direct case included testimony and exhibits presented by six witnesses, several of whom also provided rebuttal testimony. Stanley Hunley presented the calculation of the cumulative underrecovery and interest. His initial calculations were presented principally in Exhibits A-6 and A-7; revised calculations were presented on rebuttal in Exhibits A-33 and A-34.

Steven C. Foster presented testimony on 2009 coal, oil and natural gas costs, as summarized in Exhibits A-3 through A-5. David B. Kehoe presented testimony on planned and unplanned generating plant outages, as well as NOx, SO2 and urea expenses. His direct exhibits include Exhibit A-13 through A-19. David F. Ronk presented testimony on Consumers Energy's purchased, interchange, and renewable power supply costs for 2009, summarized in Exhibit A-23, with supporting details in

Exhibits A-24 through A-30, including information on MISO costs, sales to third parties, allocation of costs to the company's Renewable Resources Fund.

Direct testimony on the 2008 PA 295 transfer price calculation was presented by Thomas P. Clark, including his Exhibits A-1 and A-2, and the "roll-in" plan for the company's calculated 2009 underrecovery was presented by Laura M. Collins. Consumers Energy did not offer Mr. Miller's prefiled testimony and exhibits, which dealt with the Rate E-1 discount.

Staff presented the testimony of Elizabeth A. Rakowski, who adopted testimony originally filed by now-retired Staff member Alan Y. Droz. Staff's testimony and Exhibit S-1 made several adjustments to the calculation of the PSCR underrecovery. These adjustments include: conforming the treatment of Rate E-1 revenues and the treatment of sales to Edison Sault Electric Company to be consistent with the Commission's June 3, 2010 decision in Case No. U-15415-R; correcting the Rate GSG-2 power cost amount; using the 2008 overrecovery amount determined in Case No. U-15415-R; and rejecting the company's claim that 2004 and 2005 underrecovery balances remain to be collected, in light of the Case No. U-15415-R decision. Ms. Rakowski also addressed the cost recovery requested by the BMPs under provisions of 2008 PA 286, testifying that no inflationary adjustment is warranted for 2009 in the statutory cap on recovery.

Through the rebuttal testimony of Mr. Hunley and Mr. Ronk, the company adopted Staff's adjustments to the cumulative underrecovery amount, including interest, and revised the company calculations to match Staff's, as shown in Exhibits A-33 and A-34.

The BMPs presented nine witnesses and eleven exhibits addressing the reasonableness and prudence of fuel and variable operation and maintenance expenses incurred at seven plants. Edward P. Barrett Jr. and William "Bill" E. Smith testified on behalf of Genesee Power Station Limited Partnership, and Mr. Barrett also testified on behalf of the biomass merchant plants collectively. Thomas V. Vine testified on behalf of Viking Energy of McBain, Inc., while Neil R. Taratuta testified on behalf of Viking Energy of Lincoln, Inc., and Donald Adams testified on behalf of both companies. Philip E. Lewis testified on behalf of Grayling Generating Station Limited Partnership. Keith A. Mulka testified on behalf of Hillman Power Company, LLC. Robert Joe Tondu testified on behalf of TES Filer City Station Limited Partnership. Timothy R. Schimke testified on behalf of Cadillac Renewable Energy, LLC. Witnesses for each biomass merchant plant testified that the plant fuel and variable operation and maintenance costs were reasonable and prudent, and presented cost summaries for that plant; Mr. Barrett tallied the costs, and requested reimbursement for each company as shown on BMP-1 and BMP-2.

While Mr. Barrett's direct testimony also addressed inflationary adjustments to the statutory cap on cost recovery, the BMPs subsequently acquiesced to Staff's recommendation, and withdrew their request for an inflationary adjustment.

Michael J. McGarry, Sr., testifying on behalf of the Attorney General, took issue with several aspects of the company's reconciliation filing. He testified that the company's "transfer price" calculation, governed by 2008 PA 295, is overstated by $39,715. He also recommended substantial disallowances associated with outages at two of the company's generating plants. In his initial testimony, he testified that the company imprudently incurred $6.3 million in replacement power costs associated with repairs at Karn 1, contending that the company had failed to properly plan for needed maintenance at the unit. In supplemental testimony, prepared after certain discovery responses were received, he recommended an additional disallowance of $4.3 million, his estimate of the cost of replacement power associated with the extension of a planned outage at the Whiting Unit 3, because he concluded that the outage extension was caused by human error and could have been prevented. Mr. McGarry also testified regarding the BMPs' requested recovery, contending that the $15.4 million requested should not be included in PSCR costs.

In rebuttal to Mr. McGarry, Mr. Ronk presented testimony regarding the transfer price calculation, as well as testimony and Exhibits A-36 and A-37 regarding the replacement power costs associated with the Karn and Whiting outages, while Mr. Kehoe provided rebuttal testimony and Exhibits A-35 and A-38 regarding the causes of those outages. Also in rebuttal to Mr. McGarry, Mr. Barrett testified regarding the reasonableness and prudence of costs incurred by the BMPs, including Exhibits BMP-10 and BMP-11, while Mr. Tondu's rebuttal testimony addressed the recovery of NOx allowance costs.

MEC's witness, George E. Sansoucy, challenged the reasonableness and prudence of Consumers Energy's power supply costs for two reasons. First, he testified the company had not reasonably and prudently dispatched its generating plants, contending that certain older, smaller coal plants operated too frequently and Zeeland, a gas-fired plant, was underutilized. He recommended a disallowance of a portion of the cost of supplying fuel for Karn and Whiting based on the unreasonable and imprudent use of those plants in comparison to Zeeland or power obtained through the MISO market. In support of his analysis he presented Exhibits MEC-1 through MEC-7.

Second, he testified that the company's coal costs were not reasonable and prudent. He compared Consumers Energy's planned and actual 2009 coal costs to Detroit Edison's planned and reported actual 2009 coal costs, as shown in Exhibits MEC-8 through MEC-13. He concluded that Consumers Energy's explanations for the cost differential explained at most two-thirds of the cost differential, not considering Consumers Energy's coal transportation costs, which he also contends were too high. He recommended a disallowance of 10% of Consumers Energy's 2009 coal costs, or $41.6 million.

Mr. Ronk's rebuttal testimony, discussed in part above, also responded to Mr. Sansoucy's analysis of the dispatch of the company's generating plants. Mr. Foster presented rebuttal testimony and Exhibit A-32, to address Mr. Sansoucy's analysis of the reasonableness and prudence of the company's coal costs.

In briefs, the parties take positions generally consistent with the testimony presented by their witnesses. Consumers Energy urges the Commission to approve the cost reconciliation set forth in its Exhibits A-33 and A-34. The BMPs seek a determination that they are entitled to recover $14,838,711 under 2008 PA 286, covering costs from October 6, 2008 through December 31, 2009, with no inflationary increase in the statutory cap, plus an additional $636,073 for TES Filer City's NOx costs.

MEC seeks a disallowance of $41.6 million based on Mr. Sansoucy's analysis of the company's coal costs, or a smaller disallowance based on narrower grounds, and seeks an additional disallowance of an unquantified portion of the company's coal purchases for the Karn and Whiting plants, based on Mr. Sansoucy's analysis of the company's economic dispatch.

The Attorney General challenges payments to the BMPs under 2008 PA 286 on several grounds, including claims that the payments are preempted by federal law, that the payments conflict with express terms of the Act, and that the companies have failed to substantiate the reasonableness and prudence of the costs they seek to recover. Further, the Attorney General seeks a disallowance of $10.6 million for the replacement power costs attributable to extended power outages at Karn and Whiting. The Attorney General supports MEC's position that the company's coal costs were unreasonably high, and recommends further study to address MEC's contention that coal plants were dispatched uneconomically.

Staff's brief reviews the adjustments presented in its testimony and subsequently adopted by Consumers Energy and the BMPs. Staff also recommends that the Commission reject the NOx allowance costs claimed by TES Filer City.

The positions of the parties, and the record evidence on the disputed issues, are discussed in more detail below. Section III addresses whether net replacement power costs associated with the extended outages at Karn and Whiting should be disallowed. Section IV addresses the economic dispatch of the company's coal plants. Section V addresses the company's coal purchases. Section VI addresses the BMPs' requests for cost recovery under provisions of 2008 PA 286. Section VII addresses the Attorney General's contention that the company's transfer price calculation does not comply with 2008 PA 295.

III.

REPLACEMENT POWER COSTS

The Attorney General contends that extended outages at two plants, Karn 1 and Whiting 3, could have been avoided, and proposes disallowances for the cost of replacement power. Consumers Energy disputes the Attorney General's contention and the proposed disallowances. The Karn 1 outage is discussed in section A below; the Whiting 3 outage is discussed in section B.

A. Karn Unit 1

Mr. Kehoe discussed two extended Karn 1 outages in his direct testimony. [1] He testified that an unplanned outage began June 26, 2008 when the unit was ordered off-line due to increased vibration, and was not returned to service until February 15, 2009. He also testified that Consumers Energy discovered during this unplanned outage that the insulation surrounding the stationary coils of the generator were beginning to break down, and that the coils should be replaced as soon as possible. He indicated that Consumers Energy was not able to schedule this work during the first outage because the material and vendor support was not available, so a second outage was necessary. This second outage ran from its scheduled beginning date of September 10, 2009 until December 22, 2009, longer than the company had originally anticipated due to problems with the replacement parts, and the need to make further repairs.

[1] See Kehoe, 3 Tr 390-391.

Mr. McGarry testified that the 103 day outage at Karn 1 to replace failing stator coils could have been avoided had the replacement work been performed in conjunction with the unplanned outage described above.[2] In his opinion, Consumers Energy should have anticipated that the stator coils would need replacement, since the manufacturer's estimated life expectancy for the coils was 30 to 40 years, and the stator was already 50 years old by the time Consumers Energy initiated steps to replace it:

> The Company has reasonable knowledge about the potential breakdown of the insulation long before actual discovery during the 2008-2009 Karn 1 outage. In other words, with reasonable and prudent planning, the Company could have secured the material and vendor support for availability during the2008-2009 Karn 1 outage.[3]

In recommending a disallowance of $6.3 million to reflect the replacement cost of power purchased during the outage, Mr. McGarry relied on cost information Consumers Energy provided in response to discovery and presented in Exhibit AG-1.

Mr. Kehoe, in his rebuttal testimony, disputed that the company should have anticipated the stator replacement.[4] He testified that the coils were tested in early 2004, and that the tests showed "sufficient remaining life to reliably operate the unit until the next scheduled turbine outage – which was expected to be in 7 to 10 years."[5] He further testified that nonetheless, the company took steps in early 2008 to obtain the replacement stator coils, issuing a purchasing order June 9, 2008. Mr. Kehoe presented Exhibit A-35 to show the history of inspections and repairs associated with the Karn 1 unit. He also noted that a scheduled outage for March 2009 was postponed to accommodate the stator replacement.

---

[2] See 3 Tr 629-631.
[3] See 3 Tr 630.
[4] See 3 Tr 400-404.
[5] See 3 Tr 400.

Focusing on Mr. McGarry's testimony that the breakdown of the coil insulation should have been anticipated earlier given the life expectancy of the coils, the Attorney General does not directly address Mr. Kehoe's testimony that the process of purchasing the coils began in early 2008, or indicate how much sooner than that the replacement coils should have been ordered. If the company ordered the replacement when the stator reached 40 years of age, would it have been reasonable and prudent to hold the coils for ten years until they were needed? No analysis or discussion was presented of appropriate standards for ordering replacement equipment. Mr. Kehoe also testified that the outage to replace the coils was extended because the original equipment manufacturer's specifications for the parts were not accurate. Thus, at least a portion of the outage could not have been anticipated.

Since no party challenged Mr. Kehoe's testimony that the stator coils were evaluated in 2004 and determined to be of sufficient quality to last another 7 to 10 years, this PFD recommends that the Commission reject the requested disallowance.

B. Whiting Unit 3

The Whiting 3 generator was out of service in 2009 from April 18 through October 3. The planned 30-day outage for a general turbine inspection was extended when the inspection revealed unexpected wear and an unsafe operation condition.[6] Mr. McGarry reviewed discovery responses provided by the company, Exhibits AG-4 through AG-18, and concluded that human error led to the extension of the outage from 30 to 171 days. He testified:

[6] See Kehoe, 3 Tr 392-393.

> Based on the information provided by the Company, the April 2009 planned outage for Consumer's generating unit Whiting 3 . . . was extended due to damage to the unit's turbine as a result of several significant factors including turbine misalignment, thrust probe absence, and water induction/cold steam damage. The information provided by the Company indicates that the turbine damage was caused by human error. Company documents clearly show that "human" factors in the turbine failure and resulting outage extension included:
>
> - less than adequate performance of turbine alignment,
> - failure to verify turbine alignment,
> - less than adequate startup/shutdown procedures,
> - system operating procedures that did not conform to GE instructions,
> - personnel changes with very little turbine information handed over and understood,
> - less than adequate training in the areas where problems occurred (turbine internals, heat up/cool down rates, and turbine expansion).
>
> Additionally, after turbine repairs were completed in July 2009 and the Company was attempting to restart the unit, a misalignment of the water and steam glands caused additional damage that made restarting the unit impossible. Additional repairs were required and the unit finally restarted on October 3, 2009.[7]

He calculated the cost of replacement power for that time period based on the replacement cost of power for Karn 1, and recommended a disallowance of approximately $4.3 million as shown in Exhibit AG-19.

Mr. Kehoe and Mr. Ronk both testified in rebuttal to Mr. McGarry's recommended disallowance. Mr. Kehoe denied that any of the "human errors" identified by Mr. McGarry caused the outage.[8] He provided a copy of his response to a discovery question from the Attorney General, Exhibit A-38, indicating that "crawl through"

[7] See 3 Tr 656-657.
[8] See 3 Tr 407-412.

inspections had been performed on the turbine in 2005 and 2007, and asserting that the company's maintenance and inspection practices are consistent with industry practices for steam turbines. He testified that the company prudently operated and maintained Whiting 3.

In his second supplemental rebuttal testimony, however, Mr. Kehoe did acknowledge that human error caused one extension of the outage, indicating that the company was now in litigation with its contractor, North American Energy Service (NAES):

> After several unsuccessful attempts to restart the unit, on August 4, 2009, Consumers Energy elected to remove the IP covers and found significant damage to the 16th stage of the IP turbine. This damage was the result of differential cooling caused by misalignment of the turbine water glands, and was exacerbated by the improper alignment of the number 2 bearing. The misalignment of the water glands and the No. 2 bearing was not present during the scheduled outage period, April 2009 to May 2009.
>
> * * *
>
> [In] litigation that is currently ongoing with NAES, Consumers Energy is taking the position that these misalignment problems were the result of work performed by NAES during the outage period leading up to the July 27, 2009 restart attempt.[9]

Mr. Ronk testified regarding Mr. McGarry's calculation of the cost of replacement power for the outage.[10] He indicated that Mr. McGarry's estimate of the availability of the unit was excessive, and that he had slightly understated the fuel and variable operation expense that would have been incurred had the unit operated during the time period. Mr. Ronk testified that the correct replacement power cost for the 141 days the plant was out of service beyond the planned 30-day period was approximately $2.1 million. He also testified to the portion of the outage extension that Consumers Energy

[9] See 3 Tr 414-415.
[10] See 2 Tr 79-82; Exhibits A-36 and A-37.

considers the fault of NAES, and indicated that the replacement power cost for that portion of the outage was approximately $1 million.[11]

In his briefs, the Attorney General relies on Mr. McGarry's testimony, and the exhibits he presented, and cites the Commission's March 2, 2010 decision in Case No. U-15001-R. In its briefs, Consumers Energy relies on Mr. Kehoe's testimony, and emphasizes the 2005 and 2007 inspections Mr. Kehoe testified to.

This PFD finds that Consumers Energy failed to substantiate that it properly maintained and operated the plant, or to substantiate that the inadequate maintenance and operation did not contribute to the outage extension.

Regrettably, Consumers Energy did not present a professional report or analysis of the cause(s) of the turbine damage that was the initial basis for the outage extension. The power point or slide show presented as the "Root Cause Analysis" (RCA) and provided to the Attorney General in discovery, excerpted in Exhibits A-4, A-5, A-7 through A-13, and A-15 through A-18, does indicate significant cause for concern with the maintenance and operation of the plant.

Under the heading "Physical Roots", the RCA Slide 38 states: "The turbine alignment performed in 2003 was less than adequate." It further indicates: "'As left' or 'as-built' clearances too tight"; "Machine was set too low"; and "Machine was set too far to the left."[12] Under the same heading, and the subheading "Thrust Bearing Wear", Slide 41 indicates: "The restack of the turbine in 2003 had omitted a shim. Proper

[11] See 2 Tr 86.
[12] See Exhibit AG-7.

clearance/shim height, and alignment are key to preventing wear."[13] It further indicates: "Thrust probe taken out of scan mode. This reduced the indication the operators had to possibly identify a turbine problem."

Under the heading "Human Roots", the RCA slide 47 identifies the "Verification of alignment performed in the 2003 turbine outage" as follows:

- The turbine was left in a condition where alignment was less than adequate.
- Turbine misalignment can produce radial damage.
- Below-tolerance (tight) clearances around rotating components resulted in excessive wear.
- Reuse of components caused failure in seal strips and excessive clearances.
- Misalignment was witnessed by excessive vibration during startup activities.
- Diaphragm carriers were not squarely placed in shell.[14]

Under the "Human Roots" heading, slide 48 identifies "Startup/Shutdown procedures", and characterizes the procedures as "less than adequate", further indicating: "Direction delineated in procedures not consistent with GE instructions."[15] This slide also identifies "No use of GE starting and loading instructions," including: "No heat up/cool down instruction." And slide 49 identifies as a "Human Root" the "System Operating Procedures", indicating the following:

- Not in alignment with GE instructions.
- Comfort of operation, no issues in 50+ years.
- Instrumentation installed on components, but not used as a source for troubleshooting.
  (ARP – alarm response procedure).
- Not used because not directed to be used.[16]

[13] See Exhibit AG-8.
[14] See Exhibit AG-9
[15] See Exhibit AG-10.
[16] See Exhibit AG-11

Slide 51 also identifies under the “Human Roots” heading: “Personnel changes during period of problems and subsequent investigation/evalutation.”[17] Under this subheading, the slide notes “New Turbine System Owner in July 2008” and “New Production Manager in August 2008.” Regarding the turbine system owner, it indicates: “Very little turbine information handed over, file information and historical data very scattered”; and “Previous data taken not understood (especially as pertaining to ‘as-left’ alignment).” Regarding the new production manager, it indicates: “Turnover critical, issues related to personnel were of most concern.”

While Mr. Kehoe’s credentials are noteworthy--he has an undergraduate degree in Chemistry as well as an MBA degree--he is not an engineer and his rebuttal testimony dismissing any of the identified maintenance and operational deficiencies as a contributing factor in the outage is not persuasive and is not a substitute for an engineering analysis. While Mr. Kehoe indicates, for example, that the turbine was inspected in 2005 and 2007, he does not present an inspection report. Moreover, as noted above, the RCA slide 47 indicates that verification of the turbine alignment in 2003 was not properly done, and RCA slide 51 also indicates problems with personnel changes and record keeping for the turbine, so it is not reasonable on this record to assume that any inspections in 2005 and 2007 were competently performed, or that the results were appropriately understood. Mr. Kehoe’s interpretation of the RCA power point slides do not meaningfully add to or contradict the information presented in those slides.

[17] See Exhibit AG-12.

Moreover, Mr. Kehoe had the opportunity to present a root cause analysis in his direct testimony. That testimony indicated that he reviewed sheets prepared on each outage, and that his staff had compiled in Exhibit A-15 a sheet for each outage indicating among other things the root cause of the outage.[18] Pages 3 and 4 of Exhibit A-15, corresponding to the Whiting 3 extended outage, have no indication as to the root cause; that section of the sheet is left blank. Also, Mr. Kehoe initially reported in his direct testimony that no negligence was responsible for any of the outage extensions,[19] although Mr. Kehoe subsequently attributed approximately half the duration of this outage extension to negligence by NAES.

Turning to the portion of the outage extension Consumers Energy attributes to NAES, this PFD also agrees with the Attorney General that Consumers Energy, rather than the ratepayers, is responsible for the performance of its contractors. The Attorney General cites the Commission's decision in Case No. U-15001-R, which addressed replacement power costs resulting from a crane collapse and found that the replacement power costs attributable to the collapse should be disallowed under MCL 460.6j(13)(c):

> Section 6j(13)(c) of 1982 PA 304 requires the disallowance of replacement power costs in a reconciliation proceeding where the outage was more than 90 days in duration, where an "outage or part of the outage was . . . caused or prolonged by the utility's negligence or by unreasonable or imprudent management." MCL 460.6j(13)(c). The extension of the outage caused by the fallen crane was not this lengthy, but the statutory language is instructive. The Commission has consistently found that replacement power costs incurred as a result of

[18] See 3 Tr 388-389: "The information sheets are provided as Exhibit A-15 (DBK-3). Each sheet contains the same statistical data found on Exhibit A-13 (DBK-1). In addition, each information sheet contains (a) an expanded description of the event, (b) a final root cause, (c) what work was done to correct the root cause for forced outages or what work was performed during maintenance and periodic outages, (d) whether other work was done, (e) whether that work extended the outage and if it did, why it was done."
[19] See 3 Tr 389.

> the negligence of the utility or the employee or agent of the utility acting within the scope of its employment or agency are not recoverable. Consumers' own witness testified that "the cause of the crane collapse was that the main boom was not secured by APComPower and not left in a safe position following the evening shift." 2 Tr 81. The Commission agrees with the ALJ that proper securing of the crane at all times is the duty of the contract, who is supervised by the utility.[20]

Note that Consumers Energy is in a position to protect itself contractually from NAES's errors, and is apparently exercising its contractual remedy.

Based on the conclusion that Consumers Energy has failed to establish that it reasonably and prudently maintained and operated Whiting 3, and failed to establish that the inadequate maintenance and operation did not contribute to the outage extension, this PFD recommends that the Commission disallow costs of replacement power associated with the outage extension. In this regard, Mr. Ronk's testimony is persuasive that the replacement power costs for the 141 days of the outage extension were $2,140,882.[21] The Attorney General has not directly challenged Mr. Ronk's calculations, and in his reply brief, asked the Commission to disallow at least the amount of replacement power costs estimated by Mr. Ronk.

IV.

ECONOMIC DISPATCH

MEC challenges the dispatch of Consumers Energy's generating plants in 2009, contending that the company dispatched coal plants including Karn Units 1 and 2 and Whiting when it would have been more economical to have operated the Zeeland gas-

[20] March 2, 2010 order, Case No. U-15001-R, page 8.
[21] See 2 Tr 80.

fired plant, or to have purchased power through the MISO markets. Though rated to operate at a capacity factor of 80%, in 2009, Zeeland was dispatched at a capacity factor of 7.9%.[22] MEC relies on Mr. Sansoucy's analysis, which first compared the cost of operating Zeeland to the costs of operating several of the company's coal plants, and then compared the costs of operating the coal plants to the cost of power in the MISO market.[23]

Reviewing data from FERC Form 1 filings, Mr. Sansoucy estimated the annual fuel cost and total operating cost for each of the company's coal plants as shown in Exhibit MEC-2.[24] Exhibits MEC-4, MEC-6 and MEC-7 present Mr. Sansoucy's comparisons of the cost of operating Zeeland to the cost of operating the company's coal plants. Columns A through H of each exhibit are the same, although the comparisons made in each exhibit are different. Mr. Sansoucy determined the fuel, variable, and fixed operating costs of Zeeland with reference to efficiency and cost standards for the plant model. Monthly average fuel costs based on plant efficiency and MISO-market day-ahead natural gas prices are presented in column C of each exhibit. The sum of monthly average fuel costs plus variable and fixed operating costs for Zeeland are presented in column G of each exhibit. Mr. Sansoucy testified that the "fixed" operating costs he used do not include capital maintenance expenses. In column H of each exhibit, Mr. Sansoucy presents an alternative calculation of the

---

[22] See Exhibit MEC-5.
[23] See 3 Tr 564-570.
[24] The FERC Form-1 filing excerpts are in Exhibit MEC-3.

monthly operating costs for Zeeland, one taken from Consumers Energy's discovery responses.[25]

The right-hand columns I through N of each exhibit compare one of the Zeeland cost estimates to a cost estimate for each of the coal plants from Exhibit MEC-2. The coal plants are identified separately in each column, with the cost for each plant relevant to the exhibit shown below the plant name. Exhibit MEC-4 compares the estimated monthly total operating costs for Zeeland in column H, based the company's numbers, to one-twelfth of the annual total operating cost for each of the coal plants as shown in Exhibit MEC-2. Exhibit MEC-6 compares the estimated monthly total operating costs for Zeeland in column G, based on Mr. Sansoucy's own estimates, to the same annual total operating cost for each of the coal plants as shown in Exhibit MEC-2. Exhibit MEC-7 compares the estimated monthly fuel cost for Zeeland in column C with the average fuel cost for each of the coal plants as shown in Exhibit MEC-2. For each coal plant in columns I through N, "Xs" indicate months in which the Zeeland cost is lower than coal cost compared in that exhibit.

Mr. Sansoucy also compared his estimates of the coal plant dispatch prices to his estimate of power available in the MISO market. From Consumers Energy's Exhibit A-27, he computed average MISO variable costs for 2009 of $27.35 per MWh. He then compared this average to the fuel costs for each coal plant derived from Exhibit MEC-2, and found that the annual average fuel costs for Karn and Whiting were above the average MISO cost.

---

[25] Consumers Energy considers the information in these columns confidential and the parties agreed to entry of a protective order as noted in section I above.

Mr. Sansoucy explained the conclusions to be drawn from his analysis as follows:

> During significant portions of 2009 Consumers Energy dispatched at least some of its coal plants at a higher cost than it could have dispatched Zeeland – whether the comparison is made based only on fuel costs or based on fuel costs and total operating costs combined. Consumers also dispatched at least some of these coal plants at a higher cost than the cost at which it could have purchased replacement power from MISO during significant portions of 2009. [26]

As a result, MEC recommends an unquantified disallowance, explained as follows by Mr. Sansoucy:

> The Commission should at a minimum disallow recovery of a portion of the cost of supplying fuel for the Karn and Whiting plants based on the unreasonable and imprudent use of these plants at a higher cost than the cost at which some of this power could have been supplied by Zeeland and through MISO purchases.[27]

Consumers Energy disputes Mr. Sansoucy's analysis, relying on rebuttal testimony presented by Mr. Ronk.[28] Mr. Ronk explained that the company's dispatching is determined by MISO:

> The Company offers all of its generating units into the Midwest Energy Market that is operated by Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). Midwest ISO, through its Security Constrained Unit Commitment ("SCUC") program clears all day-ahead bids and offers to provide the lowest variable cost for operating the multi-state energy market. The Midwest ISO then uses its Security Constrained Economic Dispatch ("SCED") program to clear real-time bids and offers to provide dispatch instructions for real-time operations. The Company then dispatches the Zeeland Combined Cycle Plant (as well as all other units) in conformance with the dispatch instructions received from the Midwest ISO.[29]

---

[26] See 3 Tr 570.
[27] See 3 Tr 570; see MEC brief, page 12.
[28] See 2 Tr 70-74.
[29] See 2 Tr 71.

Mr. Ronk further explained that Zeeland is dispatched as a cycling plant, rather than as a base load plant. Because Zeeland does not run as a base load plant, bids into the MISO market reflect the start-up costs of the Zeeland plant in addition to the incremental operating costs. The company performed a study, not made part of the record in this case, indicating that it would be more expensive for ratepayers to run Zeeland as a base load plant. [30] Mr. Ronk testified that several assumptions were made in the study that would favor running Zeeland as a base load plant, including an assumption that for each hour the plant is dispatched, the locational marginal prices will for that hour will not fall below the dispatch price.[31] Even with the favorable assumptions, Mr. Ronk testified, Zeeland would be more expensive dispatched as a base load plant than the value of energy it produced.

Also, by dispatching Zeeland as a base load plant in lieu of the smaller coal-fired plans Karn and Whiting, Mr. Ronk testified that there would be additional costs incurred to maintain those plants due to the wear and tear caused by stopping and starting them.

Mr. Ronk criticized Mr. Sansoucy's analysis for two additional reasons. He testified that a dispatch analysis should be based only on variable costs (i.e. fuel plus variable operating costs) and should not include fixed costs. Because of the way Mr. Sansoucy calculated the average coal costs, they necessarily include fixed costs and are not broken out of his analysis. His fuel cost only analysis correspondingly would not include variable costs.

[30] See 2 Tr 73; 134-141, 150-151.
[31] See 2 Tr 71, 134-137.

And, he testified that Mr. Sansoucy's comparison of the Zeeland plant costs to the coal plant costs does not take into consideration that coal supplies arranged for the coal plants are long-term contracts to maintain supply reliability and price stability. In contrast, the Zeeland prices assumed in the study are essential spot market prices. Should the company intend to rely on Zeeland as a base load plant, presumably it would want to achieve the same fuel security, which would require a premium payment.[32]

Relative to MEC's claims that it would have been more economical to purchase power from MISO than to have dispatched Karn and Whiting during portions of the year, Mr. Ronk testified that the average MISO variable cost rate Mr. Sansoucy used does not reflect a value that could have been achieved at all times during the year:

> For instance, some amounts of purchases were used to fill the upper reservoir at the Ludington Pumped Storage Plant at night. Additional purchases to displace the Karn Plants or Whiting plants would have increased the LMP, perhaps to the point where it may not have been economic to have removed the Karn or Whiting units from service. Further it may have increased the pumping costs at Ludington such that the generating cost at Ludington in subsequent periods may not have been as economic.

This PFD recommends that the Commission reject MEC's proposed disallowance. In arguing Zeeland should have been dispatched more frequently, MEC has not directly responded to Consumers Energy's reliance on MISO for economic dispatch. While MEC contends that it is not seeking to have Zeeland run as a base load plant, Mr. Ronk's testimony explained that MISO makes the dispatch decisions, and if

[32] Mr. Ronk also indicated that part of the fuel supply security associated with the coal plants is attributable to on-site storage, not contemplated for Zeeland.

Zeeland is not to run as a base load plant, it will be dispatched with the start-up costs included in the dispatch price or bid.

Additionally, Mr. Ronk's testimony is persuasive that a dispatch analysis should compare the variable costs including fuel, but excluding fixed costs. The comparisons in Exhibits MEC-4 and MEC-6 include fixed, as well as variable costs, for the coal plants. And while fuel-only costs are compared in Exhibit MEC-7, variable costs are not included.

Turning to MEC's contention that coal plants were dispatched uneconomically in comparison to purchases from the MISO market, Mr. Ronk explained that the average price of power Consumers Energy actually paid for purchases from the MISO market does not reflect the price that would have been paid for purchases at other times.[33] The example he gave is that the company purchases power during off-peak hours to fill the Ludington plant reservoir. Mr. Ronk presented additional data showing average MISO prices by month in Exhibit A-37. He presented this exhibit in evaluating the cost of replacement power for the Karn 1 and Whiting 3 outages discussed above. He calculated MISO-market-based replacement power costs of $33.45/MWh for the period September 10 through December 22 and $28.97/MWh for the period May 18 through October 3.[34]

---

[33] See Ronk, 2 Tr 74.

[34] Note that the fuel cost estimates used in the company's analysis of the replacement power costs for the Whiting and Karn outages differ from the fuel cost estimates in Mr. Sansoucy's analysis. The company uses an estimate of $21.12/MWh for the variable cost of operating Karn I from September through December, including fuel, and an estimate of $21.88/MWh for the variable cost of operating Whiting 3, including fuel, from April to October. See Ronk, 2 Tr 81. These costs are below the fuel-only costs used in MEC-7 for the Karn units collectively and the Whiting units collectively.

Nonetheless, Mr. Sansoucy's analysis raises a legitimate concern, whether decisions that seem economically reasonable at each five-minute MISO interval are economically reasonable for customers, averaged over the course of an entire year. Looking at the cost comparison in Exhibit MEC-7, it is possible to compare the fuel and other variable expenses associated with Zeeland (column E or column H) to the fuel costs shown for the coal plants in columns I through M. This comparison suggests that for two or three of the months, Zeeland variable costs were less than the fuel-only component of the coal plant costs for Karn and Whiting. Mr. Ronk also acknowledged risks associated with the dispatch of the coal-fired plants, including that the plants are dispatched at a higher cost than the value of the energy produced:

> That could occur as a result of the realtime price mechanism where we would dispatch the facility at a certain level, and over the course of the hour, the five-minute pricing increments begin to decline or to rise, and the result is that the unit was operated at a level that the LMP, or the locational marginal price, wouldn't justify. So that has occurred; I haven't quantified the amount of time that would have occurred in. There would also be conditions in which we'd have the plants at minimum load and the price for either the realtime market or the day-ahead market would be less than the variable cost for operating at that minimum load.[35]

The Attorney General contends in his brief that Mr. Sansoucy's analysis warrants further study and asks the Commission to direct further analysis in the company's next reconciliation. But the next plan case would seem to be the appropriate place for an analysis, to review the company's bidding strategy for its plants, to ensure that the utility is making reasonable choices to minimize costs and maximize value to ratepayers.

---

[35] See 2 Tr 153.

V.

COAL COSTS

MEC argues that Consumers Energy failed to obtain a reasonable level of savings in its coal costs, relative to the costs forecast in its plan case, in light of steep declines in spot coal prices in 2009. MEC requests a disallowance of 10% of the company's coal costs to reflect this failure, or approximately $41.6 million. MEC's argument is based in part on Mr. Sansoucy's testimony, which he summarized as follows:

> First, the difference in actual coal costs between Consumers and Detroit Edison was even larger in 2009 than the difference in projected coal costs for 2010 that I testified about in the most recent Consumers PSCR plan case. Second, when coal prices dropped in 2009, Consumers was not able to reduce its actual coal costs nearly as much as Detroit Edison. Third, when asked, Consumers was unable to explain about one third of the difference between its actual coal costs in 2009 and those of Detroit Edison. Fourth, because Detroit Edison bought significantly more eastern coal than Consumers did in 2009, Consumers' costs – if anything – ought to be closer to Detroit Edison's and lower than they are for comparison purposes.[36]

Mr. Sancoucy also presented Exhibit MEC-8, to show the decline in coal costs from 2008 to 2009, and Exhibits MEC-9, MEC-10 and MEC-11 to support his testimony regarding the differences in costs between Detroit Edison and Consumers Energy. The Attorney General, in his reply brief, supports MEC's proposed disallowance.[37]

Consumers Energy's rebuttal to Mr. Sansoucy's testimony on this point was presented by Mr. Foster, who identified differences between Consumers Energy and Detroit Edison in support of his opinion that the coal costs for the two companies are not

[36] See 3 Tr 571.
[37] See Attorney General reply brief, pages 15-19.

comparable, and presented Exhibit A-32, summarizing differences between the companies' coal-fired generating units.[38] In response to Mr. Sansoucy's testimony indicating that Consumers Energy had only been able to quantify two-thirds of the difference between its coal costs and Detroit Edison's costs, Mr. Foster testified that Consumers Energy does not have access to the information necessary to quantify the components of such a difference.[39] In its reply brief, Consumers Energy relies on Mr. Foster's analysis, and cites the Commission's recent decision in Case No. U-16045.

In Case No. U-16045, the 2010 plan case for Consumers Energy, the Commission rejected the argument that the utility's coal costs were unreasonable because Consumers Energy had failed to provide a quantitative analysis to explain why its coal costs were higher than Detroit Edison's coal costs: "Consumers is not required to provide quantitative evaluation of the differences between its as-burned coal costs and Detroit Edison's."[40] Consistent with this decision, this PFD concludes that it is not appropriate to draw a conclusion regarding the reasonableness and prudence of Consumers Energy's coal purchasing decisions through a broad comparison to Detroit Edison's planned or actual coal costs. Not only are there reasons to expect Detroit Edison's coal costs to be different from Consumers Energy, as explained by Mr. Foster, but a utility's ability to reduce actual costs below forecast costs depends in part on the accuracy of the initial forecasts. The Commission has cautioned the parties in plan cases against spending significant time and resources debating forecast accuracy. Moreover, that Detroit Edison was able to alter contractual commitments to purchase more spot market volumes, or timed its purchases in such a way as to pay lower spot

[38] See 3 Tr 311-321. His cross-examination is found at 3 Tr 321-367.
[39] See 3 Tr 320.
[40] See February 22, 2011 order, page 12.

prices, or otherwise obtained coal prices lower than Consumers Energy does not establish on this record that any of those opportunities were available to Consumers Energy.

MEC also argues, however, that Consumers Energy missed an opportunity to lower its coal costs by taking advantage of lower spot prices, because Consumers Energy bought more western contract coal than provided for in its plan. In 2009, spot prices for western contract coal fell below projected prices, primarily due to decreased demand.[41] In its plan case, the company projected a spot mine price of $15.25 per ton for western coal, but the average price the company paid in 2009 was only $9.76 per ton.

As MEC notes, the company planned to purchase 70 to 90% of its coal needs through contract, and rely on the spot market for the remaining 10 to 30%. Instead, the company purchased only 5.85% of its coal on the spot market. Mr. Foster testified that the company purchased 412,573 fewer tons of coal, or 4%, less than the company planned, and that the as-burned volumes were 10% less than planned. He explained that the reduced volume was because on a system-wide basis, the company's coal plants ran less frequently, *i.e.* with a lower capacity factor, than planned.[42] Because the company needed less coal than its plan called for, Mr. Foster explained the effect this would have on the amount of spot coal purchased: "Because the Company's procurement practices call for the majority, or I should say a contract-to-spot mix of 70- to 90-percent contract, that coupled with the fact that our actual burn was down over a

[41] See Foster, 2 Tr 306.
[42] See 2 Tr 307.

million tons, the coal that was displaced was spot coal, so we bought less spot coal I believe than we projected."[43]

But as MEC argues, Consumers Energy not only purchased less spot coal than it planned, it purchased more western contract coal than its plan called for. Mr. Foster testified that the company planned to purchase 7,975,006 tons but actually purchased 8,085,712 tons of contract western coal, an increase of 110,707 tons.[44] Consumers Energy failed to explain on this record why it purchased additional amounts of western contract coal. Mr. Foster acknowledges the purchase, as noted above, but does not explain the basis of the change. Consumers Energy's brief indicates that the extra contract coal purchased was attributable to additional deliveries of eastern coal under a 2008 contract,[45] but Mr. Foster's testimony shows eastern contract coal purchases were down for 2009, including the additional deliveries. Also, the additional western contract coal volumes seem unrelated to the eastern contract coal deliveries. Instead, the reduction in total eastern contract coal volumes from 1,299,133 tons to 1,282,905 tons, a reduction of 16,228 tons,[46] was more than offset by the increased western contract coal volumes of 110,707 tons noted above, for an increase in total contract coal volumes of 94,478 tons. Since no explanation for this deviation from the plan was offered on the record, this PFD agrees with MEC that the company has failed to establish that this was a reasonable and prudent deviation from the plan in light of the availability of lower cost spot market western coal.

[43] See 2 Tr 345.
[44] See 2 Tr 307.
[45] See Consumers Energy reply brief, page 8 and page 10, n3.
[46] See 2 Tr 307.

As MEC seems to acknowledge, the disallowance MEC seeks—10% of the company's coal costs--is vastly disproportional to the potential increased cost of coal due to the additional western contract coal purchased, rather than spot coal. Instead, it is reasonable to determine the cost premium paid for the additional 110,707 tons of western contract coal by comparing the price paid for western contract coal to the price paid for western spot coal. As shown in Exhibit A-3, western contract coal cost $33.728 per delivered ton and western spot coal cost $31.352 per delivered ton, a difference of $2.376 per delivered ton. Thus, this PFD recommends a disallowance of $263,040 to estimate the savings that could have been achieved had Consumers Energy followed its approved plan.[47]

VI.

BIOMASS MERCHANT PLANT COSTS

In 2008 PA 286 ("Act 286"), the legislature added subsections 7, 8 and 9 to MCL 460.6a, addressing merchant plants generating electricity in whole or in part from wood wastes.[48] As discussed in more detail below, these subsections provided a mechanism for certain of these merchant plants to recover money from the large electric utilities they sell power to, over and above the amounts payable under their contracts with the utilities, and required the Commission to allow the electric utilities to recover those additional payments from their ratepayers. The subsections require the eligible merchant plants to petition the Commission for the additional recovery, cap the amount

[47] $2.376 x 101,707 = $263,040.
[48] See MCL 460.6a(7), (8), and (9).

that can be recovered by the plants in total from any utility to $1,000,000 per month, subject to future adjustments, preclude recovery by merchant plants engaged in litigation with a utility, and further limit the recovery to “the amount, if any, by which the merchant plant’s reasonably and prudently incurred actual fuel and variable operation and maintenance costs exceed the amount that the merchant plant is paid under the contract for those costs.” The subsections provide in their entirety:

> (7) If, on or before January 1, 2008, a merchant plant entered into a contract with an initial term of 20 years or more to sell electricity to an electric utility whose rates are regulated by the commission with 1,000,000 or more retail customers in this state and if, prior to January 1, 2008, the merchant plant generated electricity under that contract, in whole or in part, from wood or solid wood wastes, then the merchant plant shall, upon petition by the merchant plant, and subject to the limitation set forth in subsection (8), recover the amount, if any, by which the merchant plant's reasonably and prudently incurred actual fuel and variable operation and maintenance costs exceed the amount that the merchant plant is paid under the contract for those costs. This subsection does not apply to landfill gas plants, hydro plants, municipal solid waste plants, or to merchant plants engaged in litigation against an electric utility seeking higher payments for power delivered pursuant to contract.
>
> (8) The total aggregate additional amounts recoverable by merchant plants pursuant to subsection (7) in excess of the amounts paid under the contracts shall not exceed $1,000,000.00 per month for each affected electric utility. The $1,000,000.00 per month limit specified in this subsection shall be reviewed by the commission upon petition of the merchant plant filed no more than once per year and may be adjusted if the commission finds that the eligible merchant plants reasonably and prudently incurred actual fuel and variable operation and maintenance costs exceed the amount that those merchant plants are paid under the contract by more than $1,000,000.00 per month. The annual amount of the adjustments shall not exceed a rate equal to the United States consumer price index. An adjustment shall not be made by the commission unless each affected merchant plant files a petition with the commission. As used in this subsection, "United States consumer price index" means the United States consumer price index for all urban consumers as defined and reported by the United States department of labor, bureau of labor statistics. If the total aggregate amount by which the eligible merchant plants reasonably and prudently incurred actual fuel

> and variable operation and maintenance costs determined by the commission exceed the amount that the merchant plants are paid under the contract by more than $1,000,000.00 per month, the commission shall allocate the additional $1,000,000.00 per month payment among the eligible merchant plants based upon the relationship of excess costs among the eligible merchant plants. The $1,000,000.00 limit specified in this subsection, as adjusted, shall not apply with respect to actual fuel and variable operation and maintenance costs that are incurred due to changes in federal or state environmental laws or regulations that are implemented after the effective date of the amendatory act that added this subsection. The $1,000,000.00 per month payment limit under this subsection shall not apply to merchant plants eligible under subsection (7) whose electricity is purchased by a utility that is using wood or wood waste or fuels derived from those materials for fuel in their power plants.
>
> (9) The commission shall issue orders to permit the recovery authorized under subsections (7) and (8) upon petition of the merchant plant. The merchant plant shall not be required to alter or amend the existing contract with the electric utility in order to obtain the recovery under subsections (7) and (8). The commission shall permit or require the electric utility whose rates are regulated by the commission to recover from its ratepayers all fuel and variable operation and maintenance costs that the electric utility is required to pay to the merchant plant as reasonably and prudently incurred costs.

In its August 11, 2009 order in Case No. U-16048, the Commission approved an application from certain merchant plants specifying procedures to implement these provisions in the context of PSCR cases. In accordance with those procedures, the BMPs appeared in this reconciliation case, and presented a direct case seeking recovery of $15,161,110, plus $636,073 in costs TES Filer City incurred for NOx costs. As originally filed, the BMPs sought an increase in the $1 million per month statutory cap for 2009, to reflect inflation, but subsequently agreed with Staff's inflation calculation indicating no inflationary increase was warranted. In their briefs, the BMPs now seek to recover $14,838,711, plus the NOx allowance costs.

The Attorney General argues that the Commission should deny all recovery to the BMPs under the provisions of Act 286.[49] The Attorney General contends that the statutory provisions are preempted by federal law (PURPA), that the BMPs are not eligible for payments under the statutory provisions because the merchant plants are not directly reimbursed for fuel and variable operating and maintenance expenses under their contracts with Consumers Energy, and further that the BMPs have not shown that their costs were reasonably and prudently incurred. These arguments are discussed in subsections A through D. Section E addresses Staff's contention that additional payments to TES Filer City for NOx costs are not consistent with 2008 PA 286 because they are not attributable to a change in a law or regulation implemented after 2008 PA 286 took effect.

A. PURPA Preemption

The Public Utility Regulatory Policy Act (PURPA) has many provisions, but the pertinent provisions sought to encourage cogeneration and small power production, and directed the Federal Energy Regulatory Commission (FERC) to promulgate "such rules as it determines necessary" to encourage this power production, including rules requiring utilities to offer to sell electricity to, and purchase electricity from, qualifying cogeneration and small power productions facilities.[50] PURPA further directs: "No such rule prescribed . . . shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy."[51] This "incremental cost" limit was incorporated in FERC regulations as "avoided cost" or "the incremental costs to an

[49] See Attorney General brief at pages 4-20.
[50] See 16 USC 824a-3(f); *FERC v Mississippi*, 456 US 742, 751; 102 S Ct 2126; 72 L Ed 2d 532 (1982).
[51] 16 USC 824a-3(b).

electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[52] The regulations promulgated by FERC thus provide: "Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases."[53]

The BMPs were "qualifying facilities" or "QFs" under PURPA. The BMP contracts with Consumers Energy, Exhibits AG-20 through AG-26, were initially reviewed and approved by the Commission in a series of orders beginning in 1984, and the capacity and energy rates in those contracts were found to comply with PURPA's "avoided cost" requirement.[54] More recently, in Case No. U-13917, the BMPs had claimed that the energy payments made by Consumers Energy were no longer consistent with "avoided cost" as understood at the time of the agreements, because of changes Consumers Energy made to many of its base load plants to allow the utility to burn cheaper blends of coal. Since Consumers Energy based its payments on its average fuel costs, the payments were lower than they would have been had Consumers Energy burned predominantly high-sulfur eastern coal as it did when the agreements were entered. The BMPs argued that the avoided cost determination was based on Consumers Energy avoiding the cost of building a plant that burned high-sulfur coal. In its February 28, 2005 decision, the Commission declined to adjust the basis of the energy payments, finding that Consumers Energy was making payments using the average cost mechanism provided for in the contract:

[52] 18 CFR 292.101(b)(6).
[53] 18 CFR 292.304.
[54] See Case No. U-7990 (August 28, 1984 order); Case No. U-8062 (November 14, 1984 order); Case No. U-8562 (February 19, 1987 order); Case Nos. U-8785, U-8877 and U-9020 (June 22, 1989 order).

> The Commission is not persuaded that the power purchase agreement language pertaining to avoided energy cost payments is unclear or ambiguous. Moreover, the Commission finds that the intent of the parties with regard to the meaning and operation of the avoided cost payment mechanism is easily determined from a review of the four corners of the document. Therefore, resort to any of the contract construction measures supported by the QFs is not required and would be inappropriate.[55]

To the Attorney General, this decision further establishes that the contract payments "legally reflect" avoided cost.[56] Citing the PURPA provisions and regulations quoted above, the Attorney General contends that the payments authorized under Act 286 would exceed the avoided cost rates established in the BMPs' contracts and thus are prohibited by and in direct conflict with federal law.[57] The Attorney General further contends that any revision to the contracts already approved under PURPA is prohibited.[58]

In response, the BMPs argue that the state law payments are not preempted by PURPA.[59] They assert there is a well-recognized presumption against federal preemption,[60] and emphasize that the applicable provisions of 2008 PA 286 do not alter the payments provided for under the contract. While they dispute the Attorney General's claim that the contracts actually provide for payments at avoided cost under PURPA, they contend that the statutory payments are not payments for capacity and energy under the contracts. To the BMPs, subsections 7, 8 and 9 of MCL 460.6a must be evaluated with 2008 PA 295 ("Act 295"), which was a companion piece of legislation

---

[55] February 28, 2005 order, Case No. U-13917, page 18.
[56] See Attorney General brief at page 13.
[57] The Attorney General does not argue that PURPA expressly preempts the state law provisions ("express preemption") or that the federal government occupies the entire field of regulation so as to preclude state legislation on the subject ("field preemption").
[58] See Attorney General brief, pages 12-13.
[59] See BMP reply brief, pages 8-28.
[60] See BMP reply, page 10, citing *Medtronic, Inc v Lohr*, 518 US 470, 485; 116 S Ct 2240; 135 L Ed 2d 700 (1996).

tie-barred to Act 286. As the BMPs explain, both Acts are part of a broad, comprehensive package of state initiatives designed to encourage renewable energy and otherwise meet Michigan's power needs, which the BMPs trace back to the Governor's Executive Directive No. 2006-2 and the "21st Century Energy Plan".

Of particular importance to the instant dispute, the BMPs argue that Act 295 created a state system of renewable energy credits (RECs).[61] Section 41 of Act 295 directs the Commission to establish a renewable energy credit certification and tracking program, and provides that RECs "may be traded, sold, or otherwise transferred."[62] Section 35 of Act 295 provides that, in the absence of an agreement providing for ownership of the RECs associated with renewable energy provided under a PURPA contract, four of every five RECs (80%) belong to the electric utility purchasing the renewable energy, and one of every five RECs (20%) belongs to the generator.[63] These RECs did not exist when PURPA was enacted or when the BMP contracts were approved, and are not addressed in the contracts in Exhibits AG-20-26. To the BMPs:

> The foregoing transfer of value away from the BMPs to the utility (i.e. the REC transfer) was part of a balanced package of provisions that also included terms that benefitted the BMPs. In particular [subsections 7, 8 and 9 of MCL 460.6a] are designed to benefit the BMPs.[64]

The BMPs further respond to the Attorney General's preemption argument by arguing that the Act 286 payments govern recovery of renewable energy costs from retail customers and do not involve modifications to the wholesale rates specified by contract. The BMPs argue that payments provided for by Act 286 are not payments for

[61] The BMPs argue that by further encouraging the growth of biomass plants in Michigan, Act 295 added price pressure to the cost of existing fuel supplies for the BMPs. See BMP reply brief, page 15.
[62] See MCL 460.1041.
[63] See MCL 460.1035.
[64] See BMP reply brief, page 14.

capacity or energy and are not intended as modifications of the existing contracts. The BMPs note that subsection 9 of MCL 460.6a clearly provides that the merchant plants are not required to alter or amend their existing contracts with Consumers Energy to obtain recovery. The BMPs thus contend the legislation falls within an area of regulation left to the States under PURPA.[65]

Finally, the BMPs challenge the Attorney General's claim that even with the additional payments, Consumers Energy is paying the BMPs more than avoided cost. The BMPs review Case No. U-13917 and contend that the basis of the Commission's decision in that case was that the parties were free to agree to the payment of something other than avoided cost. The BMPs quote the Attorney General's brief before the Court of Appeals as stating the following:

> Appellants argue that the MPSC improperly concluded that Appellants waived their right to be paid avoided cost. This argument spuriously relies upon a label Appellants manipulate. Appellants' might not have signed a document labeled or entitled "waiver," but they negotiated and fully executed original contracts or contract amendments that expressly prescribe a 12-month rolling average cost calculation of energy charges. This constitutes a negotiated rate that 18 CFR 292.301 expressly permits in lieu of other provisions in Title 18, Part 292, Subpart C in the Code of Federal Regulations. In other words, Appellants agreed to a negotiated rate that may differ from calculations otherwise required pursuant to 18 CFR 292.304. Under 18 CFR 292.301 that negotiated rate agreement waived a claim to rates under 18 CFR 292.304.[66]

Staff argues that as a state agency whose responsibility it is to administer state law, the Commission need not address the Attorney General's preemption claim, although it may. Staff does not take a position on the ultimate issue, whether subsections 7 through 9 of MCL 460.6a are preempted by PURPA.

[65] See BMP reply brief, pages 16-21.
[66] See BMP reply brief, page 23.

Without rejecting Staff's analysis, it is appropriate for this PFD to address the preemption claim for the benefit of the parties and the Commission. In doing so, this PFD acknowledges that the Commission lacks the authority to declare a state law unconstitutional, but notes that the Commission has frequently addressed preemption claims in the context of carrying out its assigned duties.[67]

The appropriate starting point of a preemption analysis, as the BMPs argue, is a presumption that the state law is not preempted. This principle was explained succinctly by the U.S. Supreme Court:

> Consideration of issues arising under the Supremacy Clause "start[s] with the assumption that the historic police powers of the States [are] not to be superseded by ... Federal Act unless that [is] the clear and manifest purpose of Congress."[68]

Turning next to the PURPA provisions cited by the Attorney General, after some deliberation, FERC held that its regulations preempt state laws and policies that require qualifying facilities to be paid more than avoided costs for wholesale sales.[69] Assuming that the contracts between the BMPs and Consumers Energy "legally reflect" or must be considered to provide for the payment of avoided cost under PURPA, however, it does not follow that the payments provided for in 2008 PA 286 are payments for capacity or energy under those contracts.

Instead, as the BMPs argue, it is reasonable to consider the additional payments as compensation for the RECs which are allocated to the utilities under 2008 PA 295.

---

[67] See, e.g. *Central Transport, Inc. v PSC*, 223 Mich App 288; 566 NW2d 299 (1997).
[68] See *Cipollone v. Liggett Group, Inc*, 505 US 504; 112 S Ct 2608; 120 L Ed 2d 407 (1992), citing *Rice v. Santa Fe Elevator Corp*, 331 US 218, 230; 67 S Ct 1146, 1152; 91 L Ed 1447 (1947).
[69] See, e.g., *In re Connecticut Light & Power Co*, 70 FERC ¶61012 (1995). This decision followed FERC's decision *In re Orange and Rockland Utilities, Inc*, 43 FERC ¶ 61067 (1988), which it subsequently stayed and then vacated, 70 FERC ¶ 61014 (1995).

As noted above, the RECs at issue are created by state law and not transferred by the PURPA contracts. FERC and applicable case law appear to support the BMPs claims. In a declaratory ruling sought by certain qualifying facilities, FERC clarified that its avoided cost regulations did not contemplate the existence of RECs and the avoided cost rates for capacity and energy sold under contracts entered into pursuant to PURPA do not convey the RECs, in the absence of an express contractual provision:

> Significantly, what factor is not mentioned in the Commission's regulations is the environmental attributes of the QF selling to the utility. This is because avoided costs were intended to put the utility into the same position when purchasing QF capacity and energy as if the utility generated the energy itself or purchased the energy from another source. In this regard, the avoided cost that a utility pays a QF does not depend on the type of QF, i.e., whether it is a fossil-fuel-cogeneration facility or a renewable-energy small power production facility. The avoided cost rates, in short, are not intended to compensate the QF for more than capacity and energy.
>
> [As] noted above, RECs are relatively recent creations of the States. Seven States have adopted Renewable Portfolio Standards that use unbundled RECs. What is relevant here is that the RECs are created by the States. They exist outside the confines of PURPA. PURPA thus does not address the ownership of RECs. And the contracts for sales of QF capacity and energy, entered into pursuant to PURPA, likewise do not control the ownership of the RECs (absent an express provision in the contract). States, in creating RECS, have the power to determine who owns the REC in the initial instance, and how they may be sold or traded; it is not an issue controlled by PURPA.[70]

Because FERC has recognized that ownership of RECs is not a PURPA issue, and because companion legislation to Act 286 established by law the ownership of RECs for these facilities, it is reasonable to conclude that the Legislature intended the payments authorized under Act 286 to compensate the BMPs for the RECs assigned to the utilities under Act 295. Section 35 of Act 295 speaks directly to RECs under

[70] *In re American Ref-Fuel Co*, 105 FERC ¶ 61004, 61007 (2003) (numbered paragraphs 22 and 23), reh'g denied, 107 FERC ¶ 61016 (2004), petition for review dismissed sub nom *Xcel Energy Services, Inc v FERC*, 407 F3d 1242, 1244 (CA DC 2005).

PURPA contracts negotiated before January 1, 2008; the pertinent sections of Act 286 (subsections 7, 8 and 9 of MCL 460.6a) speak directly to PURPA contracts negotiated by the BMPs before January 1, 2008. Note that the Attorney General does not mention or address REC assignments under Act 295 in contending that the Act 286 payments are preempted.

Given a basis to interpret the legislation which is consistent with federal law, no further inquiry is required or appropriate. It is not necessary to address the authority of the Legislature to authorize payments to compensate the BMPs for increased fuel costs due to the Legislation, or to draw distinctions between retail and wholesale regulations. Having established that a clear basis exists on which to uphold the legislation, it is unnecessary to speculate on the full extent of the Legislature's or Commission's authority to regulate the relationship between Consumers Energy and the BMPs.

B. Eligibility Under MCL 460.6a(7)

Subsection 7 of MCL 460.6a, quoted in its entirety above, provides for recovery of "the amount, if any, by which the merchant plant's reasonably and prudently incurred actual fuel and variable operation and maintenance costs exceed the amount that the merchant plant is paid under the contract for those costs." The Attorney General argues that because the capacity and energy payments called for in the contracts are calculated by reference to certain Consumers Energy costs, payments under the contract cannot be said to be "[amounts] the merchant plant is paid under the contract for those costs". Thus, citing principles of statutory construction, the Attorney General argues that the BMPs do not qualify to recover any fuel and variable operating costs.[71] The BMPs dispute the Attorney General's analysis.[72]

This PFD recommends rejection of the Attorney General's argument. In framing his argument, the Attorney General mistakenly treats the statutory phrase "amount . . . paid under the contract for those costs" as a prerequisite to recovery, rather than as an element to be subtracted in determining the amount of recovery. As shown by the placement of "if" and "then" in subsection 7, the statutory prerequisites to recovery are: 1) a contract with a covered utility entered prior to January 1, 2008 with an initial term of 20 years; and 2) electricity generated under that contract prior to January 1, 2008 in whole or in part from wood or sold wood wastes. Following to its appropriate logical conclusion the Attorney General's contention, if neither the capacity nor energy payments are "for those costs" for which recovery is sought, then the "amount" paid to each merchant plant for those costs is zero. With zero subtractions, the amount that would be recovered under subsection 7 is "the merchant plant's reasonably and prudently incurred actual fuel and variable operation and maintenance costs", subject to the statutory cap in subsection 8. Rather than defeating recovery under subsection 7, the Attorney General's statutory construction would thus increase the potential recovery.

In their reply brief, the BMPs interpret the Attorney General's brief to also argue that capacity and energy payments should be subtracted from variable fuel and operating costs to determine any recovery.[73] Note that the Attorney General expressly

---

[71] See Attorney General brief, pages 14-18.
[72] See BMP reply brief, pages 29-34.
[73] See BMP reply brief, page 34-35.

disclaims making this argument, contending it too would contradict the statutory language:

> The statutory phrase “for those costs” must be given its plain meaning without further interpretation. In *In re MCI Telecommunications, Inc.*, 460 Mich 296, 414; 596 NW 2d 594 (1999), the Supreme Court concluded that when a statute does not include language, then language cannot be added to the statute by interpretation. In the case of MCL 460.6a(7), the statute could have said that the BMPs’/QFs’ cost would be compared with energy charge revenues or with dollars paid by CECo to them or to revenues used by them to cover their costs, but the statute does not state those things. Of course, if the statue did say those things, then the BMPs/QFs would have been required to compare their total revenues from CECo under their contract with their costs and would have been required to show that their costs exceeded their total revenues.[74]

Nonetheless, it is reasonable to conclude, as the BMP, Consumers Energy and Staff calculations reflect, that the energy payments under the contract are intended to cover the fuel and variable operating costs of the plant. Clearly, any generator such as a BMP would expect to recover its fixed costs as well as its variable costs over the course of a long term contract. Given the basic understanding of “capacity” payments and “energy” payments under any purchase power agreement, it is reasonable to consider the “energy” payments under the BMP contracts as designed to cover the BMPs variable costs of energy production, including fuel. Thus, it is reasonable to subtract the energy payments made to the BMPs from their total fuel and variable operating costs in determining the amount that may be recovered under MCL 460.6a(7).

C. Reasonableness and Prudence

The Attorney General and MEC argue that the BMPs have not met their burden of proof to establish that the costs presented in Exhibits BMP-1 through BMP-9 are

[74] See Attorney General brief, page 17.

reasonable and prudent.[75] The BMPs do not dispute that they bear the burden of proof, but contend they have met this burden through the evidentiary presentations of their nine witnesses.[76]

The gravamen of the Attorney General's position is that the testimony and exhibits offered by the BMPs are conclusory, and that to meet their burden of proof, the BMPs are required to establish that their costs are reasonably by reference to an objective standard or benchmark. The Attorney General relies on Mr. McGarry's testimony at 3 Tr 632-637.[77] Mr. McGarry testified to his concerns in part as follows: "From my review of the Company's testimony and that of the various BMP witnesses, this testimony fails to adequately show these expenses were reasonable and prudent."[78] He further testified: "The evidentiary record does not present comparative benchmark costs in the industry or comparable prices from other suppliers." On that point, he explained:

> Supporting testimony should identify the contract/spot strategy used to obtain the fuel, and each witness should have compared and analyzed the industry best practice to demonstrate (1) that each company's strategy was consistent with the strategies used by similarly situated biomass generators who are not seeking relief in this case and (2) that unrelated generators experienced similar total costs. One BMP witness stated that either a spot or contract would have been reasonable; nevertheless, without specifically explaining why, the witness stated that spot fuel purchases are most advantageous. Logically, these positions conflict. Since these expenses to BMPs exceed $15 million, the Commission should require more evidentiary support before ruling that the excess expenditures were reasonably and prudently incurred.[79]

---

[75] See Attorney General brief, page 18, Attorney General reply, page 14; MEC reply, pages 22-24.
[76] See BMP brief, pages 17-38; BMP reply brief, pages 36-38.
[77] Mr. McGarry's testimony was the subject of the BMPs' motion to strike, which was denied at 3 Tr 536.
[78] See 3 Tr 632.
[79] See 3 Tr 636.

Mr. McGarry also noted that Consumers Energy did not audit the BMPs. The Attorney General amplifies Mr. McGarry's objections in his reply brief, contending that each BMP witness claimed costs were reasonable and prudent "in virtually the same words."[80] The Attorney General also argues that the BMP witnesses failed to identify industry procurement practices in testifying that their practices conformed to industry standards. Finally, he observes a significant difference in the average cost from plant to plant to conclude that the BMP claims are not supported by objective evidence.

MEC's arguments, presented in its reply brief, endorse the Attorney General's position, contending that the Commission must view the BMPs' request in the context that the recovery sought is significantly in excess of the contract payment.[81] MEC characterizes the BMP testimony is "cursory" in nature, and cautions the Commission against allowing the BMPs to view the statutory payments as "drive-up ATMs". MEC further argues that costs presented in Exhibits BMP-3 to BMP-9 "are all over the map", ranging from $33.45 to $49.17 per MWh, or a difference of 47%, to emphasize "the dearth of any objective support" for the BMPs' position.

The BMPs contend instead that they presented the testimony of nine highly-qualified witnesses, and their testimony that the plant costs were reasonably and prudently incurred was entirely unrebutted. The BMPs note that Mr. McGarry did not take a position on the reasonableness and prudence of the plant costs, and they further contend that Mr. McGarry's criticisms were rebutted by Mr. Barrett's testimony.

A review of the evidence presented on behalf of each plant follows.

---

[80] See Attorney General reply brief, page 14.
[81] See MEC reply brief, pages 22-24.

1. Cadillac Renewable Energy

Mr. Schimke testified to the reasonableness and prudence of costs at the Cadillac Renewable Energy plant, and summarized the costs in his Exhibit BMP-3. Mr. Schimke is the plant manager, and testified that he has 21 years of experience in the industry, 17 of those years at the Cadillac plant, and for five years has been responsible for fuel procurement at the plant.[82] The 38 MW plant uses entirely wood waste products for fuel, all of which are purchased on the spot market "at the lowest possible price".[83] He provided examples of how the company minimizes its costs while maintaining a reliable supply, including building inventory when fuel is available at low prices, and keeping abreast of changing markets to avoid risk and realize opportunities.[84] Mr. Schimke also provided numerous examples of measures the company has taken to control its O&M costs, including ash recycling, and purchasing urea in dry form, as well as water cost reductions.[85]

2. Genesee Power Station Limited Partnership

Mr. Smith, testified to the reasonableness and prudence of the fuel and variable operation and maintenance expenses at the Genesee Power Station. Mr. Smith testified that he has 20 years of experience in the control, operation and maintenance of power plants using a variety of fuels including waste wood, and has been the plant manager for approximately 5 years.[86] Mr. Smith presented the plant's costs in Exhibit BMP-4. He testified that the company uses a blend of several wood waste materials, and has an

[82] See 2 Tr 272-273.
[83] See 2 Tr 279.
[84] See 2 Tr 280.
[85] See 2 Tr 283.
[86] See 2 Tr 229-230.

exclusive delivery service agreement with MMR, LC. He outlined the principal terms of this agreement, in addition to testifying that it was the best option for fuel available to the plant. [87] Mr. Smith also testified that the company uses competitive bidding for all large purchases to control its variable operation and maintenance expenses, and that it is continually looking for lower cost materials meeting minimum specifications for use.[88]

Mr. Barrett, the General Manager of MMR, also testified to the reasonableness and prudence of the fuel purchases MMR made under its agreement with Genesee Power Station. He has 40 years of experience in the industry, and 7 years managing wood fuel procurement for MMR.[89] He testified that it is his responsibility to ensure that the Genesee plant has a sustainable supply at the lowest price.[90] His testimony described limitations on the plant's ability to obtain a reliable source of supply due to its location in an urban rather than forested area, and the efforts MMR has taken to minimize fuel costs to plant, including establishing recycling locations and otherwise working with landscape companies, landfills and other companies to obtain wood waste that may otherwise not have a readily available place to go.[91]

3. Grayling Generating Station

Mr. Lewis is the plant manager for the Grayling Power Station, and testified to the reasonableness and prudence of the plant's fuel and variable operation and maintenance expense, presented in Exhibit BMP-5. He is a 1978 graduate of the U.S.

---

[87] See 2 Tr 235-237.
[88] See 2 Tr 238.
[89] See 3 Tr 485.
[90] See 3 Tr 486-488.
[91] See 3 Tr 489-490, 492-493.

Navy Power School, with 32 years of experience in power generation.[92] He has been at the plant since it opened in 1992, and has been responsible for fuel procurement for 10 years.

The 38 MW plant uses wood waste and tire-derived fuel referred to as "TDF". Mr. Lewis testified that the plant's wood waste fuel needs are met through an administrative agreement with AJD Forest Products, in place since 1987. Under this agreement, for a service fee, AJD Forest Products procures supplies for the plant at the "the lowest rates possible".[93] In consultation with this supplier, Mr. Lewis testified that he regularly evaluates new sources of supply, and that fuel purchasing decisions are made based on minimizing net fuel costs, while meeting permit restrictions.[94] TDF is obtained on the spot market. As to the plant's variable operating and maintenance costs, Mr. Lewis testified that the company uses competitive bidding for large purchases, is always looking for lower cost materials, and follows industry practices to control costs.[95]

<u>4. Hillman Power Co, LLC</u>

Mr. Mulka, the plant manager, testified to the reasonableness of the costs at the Hillman plant. He has 22 years of experience, in addition to studying electric power technology at the college level, and has been responsible for fuel purchases and all aspects of plant operation for the last 3 years.[96] He presented the costs for the plant in Exhibit BMP-6. The 19 MW plant uses wood waste and TDF. In purchasing wood

[92] See 2 Tr 286-287.
[93] See 2 Tr 293-294.
[94] See 2 Tr 295.
[95] See 2 Tr 297-298.
[96] See 2 Tr 214-5.

waste, he testified that he meets with suppliers, and is willing to contract with all who meet his requirements in terms of price and reliability.[97] For the tire-derived waste, after competitive bidding, the plant entered a fixed-price contract with the company (Environmental Rubber Recycling) offering the lowest delivered cost.[98] Mr. Mulka outlined additional steps the company takes to keep their fuel costs low:

> We continually reviewed the performance of all of our actual and potential suppliers, to determine if they provide appropriate pricing and performance for waste wood fuel and TDF. We facilitated and encouraged suppliers to buy private stumpage which was more cost effective. We have certified the facility for the federal Biomass Crop Assistance Program which increased our fuel vendor base, increasing competition.[99]

Mr. Mulka also discussed the efforts he undertakes to control its variable operation and maintenance expenses. In addition to stating that the company makes every reasonable effort to control these costs, he testified that the company uses predictive and preventative maintenance programs to ensure its equipment operates at peak efficiencies, citing this as an example of a prudent industry practice to minimize costs.[100]

5. TES Filer City

Mr. Tondu, one of the owners of the Filer City plant, which is jointly owned by CMS Energy, testified in support of the reasonableness and prudence of cost decisions at the plant. Mr. Tondu, who's undergraduate and graduate degrees are in geology, has been involved in energy-related activities including cogeneration alternative energy

---

[97] See 2 Tr 222.
[98] Id.
[99] See 2 Tr 223.
[100] See 2 Tr 225-226.

development since 1979.[101] He testified that he is familiar with and ultimately responsible for fuel procurement for the plant.[102] The fuel and variable operation and maintenance costs for the plant are presented in Exhibit BMP-7. Unlike the other plants, this 72.54 MW plant uses coal and coke as well as tire and wood-based waste materials as fuel. The wood waste supply comes from an adjacent papermill (Packing Company of America), the tire-based fuel (TDF) is purchased on the spot market and the coal and coke from multiple suppliers based on competitive bidding.[103] He testified that the company uses a computerized fuel cost program to minimize fuel costs,[104] and that at the time the coal and coke purchases were made, the prices agreed to were the best prices that were reasonably available.

Mr. Tondu also testified regarding the company's variable operation and maintenance expenses. In addition to testifying that the company made every reasonable effort to control these costs, he provided several examples showing how the company controls its costs through the use of competitive bidding, and capital investments such as construction of a transloading terminal on Lake Michigan, which reduced the company's variable costs.[105]

6. Viking of Lincoln, Inc. and Viking of McBain, Inc.

Mr. Tonatuta, the plant manager for the Viking of Lincoln plant, testified to the reasonableness and prudence of the variable operation and maintenance costs for the Lincoln plant. He has a BS degree in Electrical Engineering Technology and has been

[101] See 2 Tr 160.
[102] See 2 Tr 161.
[103] See 2 Tr 166-169.
[104] See 2 Tr 169.
[105] See 2 Tr 171-2.

with the plant since 1990.[106] He presented the costs for the plant in Exhibit BMP-8. Mr. Tonatuta testified that measures to control costs include shutting equipment down when it is not in use, maintaining it in accordance with an established program to ensure peak efficiency, avoiding unnecessary repairs or modifications.[107]

Mr. Vine, the plant manager for Viking of McBain plant, testified to reasonableness and prudence of operating and maintenance costs at the McBain plant. Mr. Vine, who has a B.S. degree in engineering, has a 25-year background in the nuclear power industry, and was the maintenance manager for the University of Iowa Power Plant for 3 years before becoming plant manager at Viking of McBain.[108] He presented the fuel and variable operation and maintenance expenses for the plant in Exhibit BMP-9. As with Viking of Lincoln, above, the plant controls its operating costs through the use of competitive bidding for large purchases, market monitoring, shutting equipment down when not in use, and following a maintenance plan consistent with industry practices.[109]

Mr. Adams, regional fuel manager for Viking Energy, is responsible for fuel purchases for both Viking of McBain and Viking of Lincoln, and testified to the reasonableness and prudence of those purchases. His background includes 5 years in the U.S. Navy as a boiler technician, and 20 years with Viking, including 15 years in procurement, contract negotiation and administration.[110] Both 16 MW plants use wood waste and some TDF. He testified that most of the company's purchases are spot

[106] See 2 Tr 241.
[107] See 2 Tr 248.
[108] See 2 Tr 252-253.
[109] See 2 Tr 259-260.
[110] See 2 Tr 264.

purchases, and that few suppliers are willing to enter fixed contracts due to the volatility of the market.[111] He further testified that cost and reliability were his key considerations, that he tracked prices weekly to determine who could deliver the most reliable, lowest cost fuel, and that considering the volumes and timing of purchases and the reliability of supply, the company selected the lowest prices available at the time of purchase.[112]

7. Discussion

In reviewing the testimony of the BMP witnesses in its entirety, this PFD concludes that the Attorney General's and MEC's characterization of the evidence as merely "conclusory" or "cursory" does not fully credit the level of detail provided or the experience and/or qualifications of the witnesses testifying. For each plant, a witness or witnesses testified with principal responsibility for the fuel and variable operating costs[113] incurred at the plant. Each witness demonstrated significant experience in the industry, as well as appropriate levels of education or training, which no party challenged. For each plant except TES Filer City, the plant manager testified; and where the plant manager did not make the fuel-related decisions, the appropriate witness responsible for those decisions testified in addition. For TES, Mr. Tondu testified as an owner of the plant, and indicated that he was responsible for the procurement and operational decisions.

The BMP witnesses did testify that the costs for their plants were "reasonable and prudent", the statutory test. But such "conclusory" statements are not inadmissible

[111] See 2 Tr 266-267.
[112] See 2 Tr 268.
[113] The witnesses used common definitions of variable operation and maintenance expenses.

because they mirror the ultimate finding the BMPs seek in this case, nor are they wholly devoid of evidentiary significance. On this record, the witnesses testified not just to their conclusions that the costs for their plants were reasonable and prudent, but explained the fuel supply procurement and operations and maintenance cost policies they use. While examples were often provided rather than a comprehensive review of all cost elements and decisions, the examples were intended to show cost minimization practices. The witnesses' testimony consisted of more than a pro forma recitation that costs are reasonable and prudent. The witnesses were not cross-examined on their testimony in this regard. Nothing on this record thus suggests that the witnesses were not candid, capable and well-informed.

The Attorney General and MEC also point to the variability of the costs among the plants to support their argument that the BMPs have not met their burden of proving the costs reasonable and prudent. But variability of cost is not evidence of unreasonableness. The plants are not all the same, ranging in size from 16 MW to 72.54 MW, and using different mixes of fuels. Note that some of the plants can burn TDF, and one, TES, burns substantial amounts of coal and coke. Mr. Barrett testified for the Genesee plant, identified by MEC as having the highest cost, $49.17 per MWh. As noted above, he explained the difficulties associated with obtaining fuel given the plant's location in an urban area, not near to forests.[114] Mr. Barrett also testified on rebuttal that numerous factors including transportation costs play an important role in a generator's total costs.[115]

---

[114] See 3 Tr 490, 492.
[115] See 2 Tr 508.

As the Attorney General and MEC note, some of the plants relied more heavily or entirely on spot purchases rather than contracts for fuel supply, while others relied more heavily on exclusively on contracts to meet their fuel needs. Mr. Schimke provided testimony unrebutted on this record:

> There are two schools of thought regarding the relative advantages and disadvantages of buying on the spot market versus signing long term contracts. Both approaches are reasonable, but we have elected to purchase on the spot market because, with the variety of suppliers in our particular location, it is our best judgment that the spot market will provide us with the lowest overall cost.[116]

Mr. Barrett, in his rebuttal testimony, also testified that purchasing fuel via the spot market or via long-term contracts are both reasonable procurement practices.[117]

Mr. McGarry's principal objection to the BMP witnesses testimony was the lack of objective standards provided by which to measure the reasonableness and prudence of the costs for each plant. Mr. McGarry acknowledged, however, that he could not identify any objective standards or benchmarks that should be used. And while he did suggest that the BMPs justify their costs by reference to other biomass plants not seeking recovery in this proceeding, Mr. Barrett's rebuttal testimony explained:

> Mr. McGarry is arguing that the BMPs should have provided data that simply does not exist. The BMPs are all merchant plants that use wood or wood waste for fuel. There is no market price information published for wood or wood waste as there is for coal or natural gas. The NYMEX simply does not produce futures prices for wood or wood waste fuel.
>
> Additionally, it is important to note that all of the qualifying BMPs in Michigan presented their fuel and variable O&M date in this proceeding. Thus, the universe of cost data for similarly situated Michigan BMPs has, in fact, been presented to the Commission. To the extent that Mr. McGarry is suggesting that the BMPs should have provided comparative

[116] See 2 Tr 279.
[117] See 3 Tr 509.

cost data for BMPs located in other jurisdictions, I am unaware of where any such data exists.[118]

While objective standards and benchmarks are an important and legitimate tool in evaluating costs, just as Mr. McGarry testified, on this record no one has identified any such standards.[119] Moreover, the Commission is faced with a generalized statutory requirement that the BMPs demonstrate that their costs were reasonable and prudent. No further instruction was given by the Legislature. While the Commission has the authority to require more detailed showings by the BMPs in future cases, the Commission has not yet done so. Since this is the first case arising under this new statute, and under the procedures put in place in Case No. U-16048, this PFD concludes that the BMPs have adequately demonstrated the reasonableness and prudence of their costs.

The Attorney General and MEC nonetheless express a legitimate concern that the Commission have adequate information to evaluate the reasonableness and prudence of BMP costs to avoid using the statute “as a drive-up ATM.” While it would be appropriate for the Commission to direct the BMPs to provide an analysis in future cases that incorporate objective standards or benchmarks, since no such standards or benchmarks have been identified on this record, this PFD recommends only that the Commission invite the parties to the next case in which BMP costs are considered to provide an evaluation of those costs in reference to appropriate objective standards.

[118] See 3 Tr 508-509.
[119] See Exhibit BMP-10.

D. Time period

The Attorney General's fourth challenge to the BMPs' proposed cost recovery concerns only costs incurred by the BMPs in 2008. The BMPs request recovery of $2,838,710 attributable to fuel and variable operations and maintenance expenses incurred from the effective date of Act 286 (October 6, 2008) to December 31, 2008, as limited by the monthly statutory cap. The BMPs rely in part on the following provision of the Commission's August 11, 2009 order in Case No. U-16048:

> Upon the issuance of a final order approving these procedures, the BMP's will submit a single invoice to CECo listing the amounts to be paid to each of the BMPs for all of the recoverable costs that the BMPs incurred between October 6, 2008 (the effective date of Public Act 286 of 2008) and the end of the last full month prior to the month in which the Commission's final order is issued. The BMPs' invoice will identify the actual number of megawatt hours that each BMP generated, the fuel and variable operation & maintenance payments that it received from CECo, and the BMP's actual fuel and variable operation & maintenance costs. . . . Such payments will be reviewed and approved, amended or disapproved in the context of CECo's 2009 PSCR reconciliation proceeding.[120]

The Attorney General argues that the Commission should reject payments to the BMPs for costs incurred from October through December, 2008, contending that costs incurred prior to the 2009 plan year cannot be addressed in this reconciliation of Consumers Energy's 2009 PSCR costs. The Attorney General cites MCL 460.6j(12), and argues that nothing in MCL 460.6a(7)-(9) provides for an application to be filed to recover 2008 costs after the close of the reconciliation case covering the 2008 plan year. To the Attorney General, MCL 460.6j(12) precludes the Commission from considering these costs in this case, even though the Commission's order in

[120] Order, Exhibit A, paragraph 6.C.

Case No. U-16048 provided for cost recovery under MCL 460.6a(7)-(9) to be addressed in this case/reconciliation cases.

This PFD concludes that the disputed costs can be recovered through the mechanism established in the Commission's order in Case No. U-16048. The costs at issue are not PSCR costs per se. The Commission has chosen for administrative convenience to review the costs *in the context of* a PSCR reconciliation proceeding, but as explained above, these costs are not contractual payments for capacity or energy under the PURPA contracts. Instead, these are separate payments expressly provided for by the Legislature. Had the Legislature wanted to mandate that the payments provided for in subsection 7 of MCL 460.6a be included in the PSCR process, it could have done so. For example, in Act 295, the Legislature made specific provision for the treatment of costs of renewable energy obtained after October 6, 2008 in PSCR proceedings.[121] Instead, the legislative direction to the Commission in MCL 460.6a(7) is simply "to permit or require the utility to recover these costs." Moreover, under the procedures established, Consumers Energy was not to pay any invoices for these payments until 2009, making it appropriate and timely to review them in the context of the 2009 PSCR proceeding.

E. <u>TES Filer City NOx costs</u>

TES is also seeking recovery of the cost of certain NOx allowances purchased in 2009. Mr. Tondu testified that TES spent $636,073 for the purchase of both seasonal

[121] See MCL 460.1047, discussed in section VII below.

and annual NOx allowances related to plant emissions.[122] Subsection 8 of MCL 460.6a states in pertinent part:

> The $1,000,000.00 per month payment limit under this subsection . . . shall not apply with respect to actual fuel and variable operation and maintenance costs that are incurred due to changes in federal or state environmental laws or regulations that are implemented after the effective date of the amendatory act that added this subsection.

As noted above, the effective date of Act 286 was October 6, 2008. TES argues that its NOx allowance costs are attributable to state regulations that were not implemented until after this date. To TES, implemented means "completed, fulfilled and put into effect".[123]

As background, under the federal Clean Air Act (CAA), states retain primary responsibility for setting air quality standards within their borders, as long as they comply with national standards established under the CAA. 42 USC 7410 provides for states to have "State Implementation Plans" or "SIPs" reviewed and approved by the EPA. In Michigan, the DEQ sets air quality standards pursuant to Part 55 of the Natural Resources and Environmental Protection Act, MCL 324.5501 *et seq.* Michigan's first SIP was approved by EPA as early as 1972.[124] The Clean Air Interstate Rule (CAIR), promulgated by EPA in 2005, required states to revise their SIPs to reduce emissions of NOx and SO_2. EPA also promulgated a "Federal Implementation Plan" (FIP) that would apply to state sources in the absence of an approved SIP.[125]

TES argues that the Michigan "SIP" requiring it to acquire NOx allowances became effective October 19, 2009, the effective date of the approval by the EPA of

[122] See 2 Tr 173.
[123] See BMP brief, page 53, citing the Concise Oxford Dictionary.
[124] See 37 Fed Reg 10873 (May 31, 1972).
[125] See 71 Fed Reg 25,328.

rules promulgated by the MDEQ, "or, more appropriately, November 30, 2009, by which time generators of such emissions were required to have purchased their 2009 seasonal allowances."[126]

Staff argues that TES has not established that it qualifies for the exemption from the statutory cap. Staff argues that TES's requirement to participate in EPA's NOx trading program began before the 2009 SIP approval. TES has yet to explain, what, if any, post-2008 changes in the regulatory scheme constituted changed regulations.

"Implement" has varying definitions. The American Heritage Dictionary defines implement as: "To provide a definite plan or procedure to ensure the fulfillment of."[127] The definition in the Dictionary of Modern Legal Usage contains a caution, as follows:

> Implement, v.t., is a vogue word beloved by jargonmongers, in whose language *policies are implemented*. *Carry out* is usually better, and certainly less vague.[128]

Nonetheless, even using the definition proffered by TES, the statutory focus is still on *changes* in federal or state environmental laws. The regulatory history presented by TES does not show that the costs it incurred in 2009 were due to changes in the applicable environmental laws or regulations that were put into effect after October 6, 2008. TES cites the August 18, 2009 EPA approval of Michigan's SIP, but in granting that approval, EPA recognized:

> This action merely approves State law as meeting Federal requirements and would impose no additional requirements beyond those imposed by State law. . . . Because this action approves pre-existing requirements under State law and would no impose any additional enforceable duty beyond that required by State law, it does not contain any unfunded

[126] See BMP brief, pages 47-53.
[127] *The American Heritage Dictionary of the English Language* (1981).
[128] See Garner, *A Dictionary of Modern Legal Usage* (1995).

> mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995.[129]

TES also cites the December 20, 2007 conditional approval of Michigan's SIP, explaining that this conditional approval lapsed into a disapproval effective December 20, 2008. But the conditional approval from EPA stated the following: "Where, as here, the final rule relieves obligations rather than imposes obligations, affected parties, such as the State of Michigan and CAIR sources within the State, do not need time to adjust and prepare before the rule takes effect."[130]

TES has not identified in any of the rules and regulations taking effect after October 6, 2008, any substantive change that required TES to obtain the NOx allowances. Instead, it appears that TES's obligations can be traced to rules promulgated by the MDEQ effective June 25, 2007,[131] and may have been imposed by regulations adopted even earlier. For this reason, this PFD agrees with Staff's analysis, that TES has failed to show that the costs it incurred in 2009 were attributable to changes in the environmental laws implemented after the effective date of Act 286.

VII.

TRANSFER PRICE CALCULATION

The Attorney General also challenges the transfer price calculation presented in Consumers Energy's reconciliation.[132] MCL 460.1047 provides for utilities to recover the "incremental cost" of renewable energy purchased in accordance with Act 295. The

[129] See 74 Fed Reg, pages 41637, 41640 (August 18, 2009).
[130] 72 Fed Reg, pages 72256, 72261 (December 20, 2007).
[131] See 2007 MR 12, R 360.1802a et seq.
[132] See Attorney General brief, pages 20-24.

incremental cost calculation requires that a portion of the costs be recovered through the PSCR process. MCL 460.1047(2)(b)(iv) provides for the allocation of renewable energy costs between PSCR costs, and incremental costs through use of a price mechanism:

> After providing an opportunity for a contested case hearing for an electric provider whose rates are regulated by the commission, the commission shall annually establish a price per megawatt hour. . . . In setting the price per megawatt hour under this subparagraph, the commission shall consider factors including, but not limited to, projected capacity, energy, maintenance, and operating costs; information filed under section 6j of 1939 PA 3, MCL 460.6j; and information from wholesale markets, including, but not limited to, locational marginal pricing. This price shall be multiplied by the sum of the number of megawatt hours of renewable energy and the number of megawatt hours of advanced cleaner energy used to maintain compliance with the renewable energy standard. The product shall be considered a booked cost of purchased and net interchanged power transactions under section 6j of 1939 PA 3, MCL 460.6j. For energy purchased by such an electric provider under a renewable energy contract or advanced cleaner energy contract, the price shall be the lower of the amount established by the commission or the actual price paid and shall be multiplied by the number of megawatt hours of renewable energy or advanced cleaner energy purchased. The resulting value shall be considered a booked cost of purchased and net interchanged power under section 6j of 1939 PA 3, MCL 460.6j.

The Commission has labeled this price the “transfer price.” MCL 460.1049(3)(c) further provides for the Commission to establish this price in annual renewable energy plan reconciliation proceedings.

Mr. Clark presented the company’s transfer price calculations, shown in Exhibits A-1 and A-2. He explained that the transfer price is only applied to production from provider-owned renewable energy systems, purchases of energy and capacity and RECs through renewable energy contracts, and production from Commission authorized renewable energy systems, and that in 2009, Consumers Energy only had 3 purchase agreements to evaluate, since costs for renewable energy systems for which recovery was provided in rates approved as of October 6, 2008, are recovered as part of power supply costs and general rates. Mr. Clark testified that he developed the transfer price for use in this case by multiplying monthly quantities delivered and booked in 2009 for each agreement by the schedule of energy and capacity values established in Case No. U-15805A. Adding the total “transfer costs” for each agreement, and dividing by the total deliveries, yielded an average transfer price of $44.798/MWh.

Mr. McGarry objected to the company’s calculation, and proposed a reduction of approximately $39,000 in the company’s $90,000 total transfer cost. Mr. McGarry testified that the transfer price should not be higher than the actual Locational Marginal Prices established over the plan year to properly identify the incremental costs of renewable energy:

> The amount of dollars that should flow into the annual PSCR reconciliation should be based on the lower of the actual price for renewable energy or the alternative [Locational Marginal Price]. If the actual cost is higher than the LMP price, then the remainder of the costs stays in the renewable energy plan reconciliation so that the balance of the total reasonable and prudent costs incurred for a renewable energy contract is recovered through that mechanism, not through the PSCR reconciliation.[133]

Recognizing that locational marginal prices have changed since the transfer prices used in the company’s calculations were established, Mr. McGarry recommended that the transfer price used in determining PSCR expenses in this case be reduced by 45% to reflect the reduction in Locational Marginal Prices from the forecast in the plan case to the actual prices experienced over the plan period. The 45% reduction in transfer price leads to a $39,715 reduction in the PSCR expenses for renewable energy.

[133] See 3 Tr 624

In rebuttal, Mr. Ronk testified that the company's transfer price calculations are consistent with the Commission's August 25, 2009 decision in Detroit Edison's renewable energy plan case, Case No. U-15806, and with the Commission's approval of Consumers Energy's August 26, 2009 filing in Case No. U-15805.[134] In the cited decision in Case No. U-15806, the Commission adopted Staff's recommendation that for third-party PPAs, "the schedule of transfer prices most recently approved shall become the floor price for PSCR recovery." The Commission explained its rationale as follows: "the primary reason for setting the transfer price schedule as a floor for any project of PPA is to provide the utility with a means of planning its renewables acquisition program to meet its renewable portfolio target without exceeding the caps on the surcharge defined in Act 295."[135]

Consumers Energy's brief reiterates the company's reliance on these orders, and indicates that the transfer price should not be established in this proceeding, but in a renewable energy plan reconciliation proceeding as provided in MCL 460.1049. While the Attorney General continues to seek the $39,715 adjustment recommended by Mr. McGarry in his reply brief, the Attorney General does not directly address or respond to the company's reliance on these orders.

This PFD finds that the company has calculated the transfer price in accordance with the Commission's orders as cited, and no further adjustment to the transfer price is warranted. This PFD further agrees with Consumers Energy that the PSCR reconciliation is not ordinarily a forum to establish the transfer price, since the transfer

[134] See October 13, 2009 order, Case No. U-15805.
[135] See August 25, 2009 order, page 12.

price must otherwise be established annually, and the company may petition at any time to have the transfer price revised.

VIII.

CONCLUSION

Based on the foregoing discussion and findings, this PFD recommends that the Commission approve Consumers Energy's PSCR reconciliation with the following exceptions:

1. A disallowance of $2,140,882 is appropriate to reflect the company's failure to establish that human error was not the cause of the extended outage at the Whiting 3 plant;

2. A disallowance of $263,040 is appropriate to reflect the company's failure to establish that its decision to take additional contract volumes of western coal was reasonable and prudent, given declines in spot market prices for western coal.

This PFD further recommends payments to the BMPs under MCL 460.6a(7)-(9) should be approved in the amount of $14,838,711, to be allocated using the method reflected in Exhibit BMP-1. No additional allowance for NOx costs incurred by TES Filer City should be made.

This PFD further recommends that in its next plan case, Consumers Energy be directed to provide an analysis of the economic dispatching of its generation assets, to demonstrate that the utility is dispatching its assets prudently and in the best interests of its ratepayers.

STATE OFFICE OF ADMINISTRATIVE
HEARINGS AND RULES
For the Michigan Public Service Commission

Sharon L. Feldman

Digitally signed by Sharon L. Feldman
DN: cn=Sharon L. Feldman, c=US, email=feldmans@michigan.gov
Date: 2011.03.30 11:57:54 -04'00'

Sharon L. Feldman
Administrative Law Judge

Issued and Served:
drr